(12) INTERNATIONAL APPLICATION PUBLISHED UNDER THE PATENT COOPERATION TREATY (PCT)

(19) World Intellectual Property Organization
International Bureau

(43) International Publication Date
10 September 2004 (10.09.2004)

PCT

(10) International Publication Number
WO 2004/076815 A1

(51) International Patent Classification[7]: E21B 49/00, 47/06

(21) International Application Number: PCT/GB2004/000760

(22) International Filing Date: 26 February 2004 (26.02.2004)

(25) Filing Language: English

(26) Publication Language: English

(30) Priority Data:
60/450,521 27 February 2003 (27.02.2003) US
60/485,295 7 July 2003 (07.07.2003) US

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(81) Designated States (*unless otherwise indicated, for every kind of national protection available*): AE, AG, AL, AM, AT, AU, AZ, BA, BB, BG, BR, BW, BY, BZ, CA, CH, CN, CO, CR, CU, CZ, DE, DK, DM, DZ, EC, EE, EG, ES, FI, GB, GD, GE, GH, GM, HR, HU, ID, IL, IN, IS, JP, KE, KG, KP, KR, KZ, LC, LK, LR, LS, LT, LU, LV, MA, MD, MG, MK, MN, MW, MX, MZ, NA, NI, NO, NZ, OM, PG, PH, PL, PT, RO, RU, SC, SD, SE, SG, SK, SL, SY, TJ, TM,

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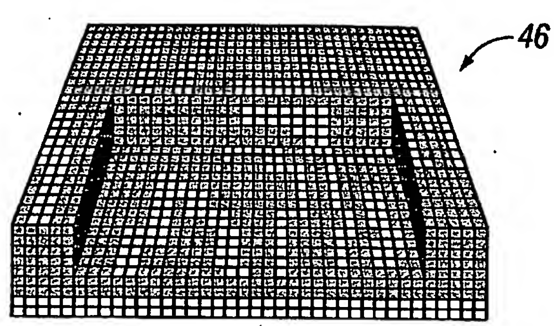
(54) Title: DETERMINING AN INFLOW PROFILE OF A WELL



(57) Abstract: A system that is usable with a subterranean well includes a pressure sensor and a unit. The pressure sensor is adapted to obtain pressure measurements along at least a portion of the well while the well is in production without requiring an intervention in the well. The unit is coupled to the pressure sensor and is adapted to provide a model and estimate an inflow profile of the well in response to the pressure measurements. In some embodiments of the invention, the well may be a horizontal well. Furthermore, the unit may be adapted, in some embodiments of the invention, to further base the estimation of the inflow profile on temperature measurements taken inside the well.

WO 2004/076815 A1

TN, TR, TT, TZ, UA, UG, US, UZ, VC, VN, YU, ZA, ZM, ZW.

(84) Designated States *(unless otherwise indicated, for every kind of regional protection available)*: ARIPO (BW, GH, GM, KE, LS, MW, MZ, SD, SL, SZ, TZ, UG, ZM, ZW), Eurasian (AM, AZ, BY, KG, KZ, MD, RU, TJ, TM), European (AT, BE, BG, CH, CY, CZ, DE, DK, EE, ES, FI, FR, GB, GR, HU, IE, IT, LU, MC, NL, PT, RO, SE, SI, SK, TR), OAPI (BF, BJ, CF, CG, CI, CM, GA, GN, GQ, GW, ML, MR, NE, SN, TD, TG).

Published:
— *with international search report*

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DETERMINING AN INFLOW PROFILE OF A WELL

BACKGROUND OF THE INVENTION

Field of the Invention

The invention generally relates to determining an inflow profile of a well without performing an intervention in the well.

Description of Related Art

It is often desirable to obtain the inflow profile of a well, such as a horizontal well. The inflow profile may indicate not only the location of the liquids and gases flowing into the well but also the content of the inflow. The information gained from the inflow profile permits the proliferation of horizontal wells to follow the continued advances in drilling technology.

For mature fields, the determination of the inflow profile is also desirable for purposes of closely observing and maintaining these fields due to the inability of lift and surface facilities to cope with excessive volumes of sweeping fluids. Wells in new and emerging fields may also require close observation and maintenance, due in part to the relative significance of each well in fulfillment of field production quotas and the undesirability of intervention.

Determining the inflow profile of a well typically requires a "production logging" operation. This operation is an intrusive technique for horizontal wells and usually requires running a tool string on coiled tubing to access the horizontal section of the well. The use of production logging may be undesirable because the logging only provides a snapshot in time. Furthermore, production logging may be only applicable to a subset of the horizontal well population. For example, pumping wells typically cannot be logged unless they have a bypass mechanism, long horizontal wells typically cannot be logged because of coiled tubing access limitations, and subsea wells typically cannot be logged in a cost-effective manner because these wells require intervention vessels.

Thus, there is a continuing need for a means to determine the inflow profile of a well without intervention.

BRIEF SUMMARY OF THE INVENTION

In an embodiment of the invention, a technique that is usable with a subterranean well includes obtaining pressure measurements during the flowing of the well without intervening in the well. The technique includes using a model to determine from the pressure measurements an inflow profile of the well. In some embodiments of the invention, the well may be a horizontal well, and in some embodiments of the invention, temperature measurements may also be used to determine the inflow profile.

Advantages and other features of the invention will become apparent from the following description, drawings, and claims.

BRIEF DESCRIPTION OF THE DRAWINGS

Fig. 1 is a schematic diagram of a horizontal well according to an embodiment of the invention.

Fig. 2 is a flowchart depicting a technique to generate an inflow profile for the well of Fig. 1 according to an embodiment of the invention.

Fig. 3 is a perspective view depicting a reservoir permeability distribution.

Fig. 4 is a graph depicting well production profiles and a water-cut profile.

Fig. 5 is graph depicting fluid influx profiles at different water-cuts for selective perforations.

Fig. 6 is a graph depicting oil and water influx profiles along the wellbore.

Fig. 7 is a graph depicting a saturation cross section.

Fig. 8 is a graph depicting water cut behavior of the well.

Fig. 9 is a graph depicting pressure profiles of the well at different water-cuts.

Fig. 10 is a graph depicting pressure gradient profiles where sensitivity to water-cut is weak for selective perforations.

Fig. 11 is a graph depicting pressure gradients along the wellbore at different water-cuts for liner completion.

Fig. 12 is a graph depicting fluid influx profiles for different water-cuts.

Fig. 13 is a graph depicting pressure profiles that are affected by the trajectory of the well.

Fig. 14 is a graph depicting different pressure profiles for different free gas rates.

Fig. 15 is a graph depicting free gas influx profiles that correspond to the pressure profiles depicted in Fig. 14.

Fig. 16 is graph depicting true influx and inverted influx estimates from a pressure profile when wellbore hydraulic parameters are known.

Fig. 17 is a graph depicting true influx and inverted influx estimates from a pressure profile when liner roughness is underestimated by a factor of two.

Fig. 18 is a graph depicting true influx and inverted influx estimates from a pressure profile for uniform drift in pressure measurements.

Fig. 19 is a graph depicting the result of inversion with a random pressure drift.

Fig. 20 is a graph depicting true and inverted total fluid influxes for a two-phase flow.

Fig. 21 is a graph depicting simulated and inverted influxes per fluid phase.

Fig. 22 is a graph depicting the reduction of bottom hole temperature at different times.

Fig. 23 is a graph depicting temperature profiles along the wellbore for low volatile oil.

Fig. 24 is a graph depicting temperature profiles along the wellbore for high volatile oil.

Fig. 25 is a block diagram of a computer according to an embodiment of the invention.

DETAILED DESCRIPTION OF THE INVENTION

In accordance with embodiments of the invention, a technique to derive an inflow profile

of a well (a horizontal well, for example) is performed without requiring physical intervention in the well. Instead of such intervention, the technique includes installing sensors ("permanent" sensors) in the well during the completion process, interrogating the sensors under controlled conditions during the production phase of the well, and applying certain mathematical techniques (multi-physics inversion and dual-continuum media, otherwise called "inversion,") to measurements that are acquired from the sensors. The sensors may include a multipoint pressure sensor and may also include a distributed temperature sensor array. These sensors may be installed in a horizontal section of the well. Additionally, in some embodiments of the invention, the technique may include placing a multiphase flow meter downstream of the horizontal section, such as above a production packer, for example.

Referring to Fig. 1, an embodiment of a horizontal well in accordance with the invention includes a main vertical wellbore 10 and a horizontal wellbore 11 that traverses a hydrocarbon formation 14. As depicted in Fig. 1, a production tubing 12 extends through the vertical wellbore 10 and horizontal wellbore 11. Although the production tubing 12 is depicted in Fig. 1 as extending to the end of the well, in some embodiments of the invention, the production tubing 12 may not extend to the end of the well. For example, in some embodiments of the invention, the production tubing 12 may be deployed along a stinger.

In some embodiments of the invention, a sensor 16 is mounted on the outside of the production tubing 12 and thus, may be run into the well with the production tubing 12. In some embodiments of the invention, the production tubing 12 may include a multiphase flow meter 13 that is downstream of the horizontal wellbore 11. For example, in some embodiments of the invention, the production tubing 12 may include a packer 15, and the flow meter 13 may be located above the packer 15, as depicted in Fig. 1.

The well that is depicted in Fig. 1 is one of many possible horizontal wells that may be used in accordance with the techniques described herein. These horizontal wells include wells that traverse homogeneous or heterogeneous formations, those that are subject to bottom-water drive and those with sand completions, such as in liner or screen completions. In some

embodiments of the invention, the formation may be unconsolidated.

The sensor 16, in some embodiments of the invention, may be deployed within the tubing 12 or may be mounted to the outside of a well casing (not depicted in Fig.1) that lines the vertical 10 and horizontal 11 wellbores. The sensor 16, in some embodiments of the invention, may be deployed along a stinger, along the liner, or may be mounted to the outside of a sand screen. In some embodiments of the invention, the sensor 16 may be a pressure sensor that measures pressure at multiple points along the length of the wellbores 10 and 11. As a more specific example, in some embodiments of the invention, the sensor 16 is a multi-point sensor that provides single point measurements that are made at different locations. In another embodiment of the invention, the sensor 16 may be a distributed sensor such that pressure is measured along the length of the sensor. The sensor may be electrical, mechanical or optical, depending upon the particular embodiment of the invention. In some embodiments of the invention, the sensor 16 may be "permanent" in that the sensor 16 is installed with the completion and provides sensed values during production without requiring intervention into the well.

In some embodiments of the invention, the measurements that are made by the sensor 16 may be transmitted to the surface via a cable 17. It is noted that the sensor 16 may also include the cable 17. For example, in some embodiments of the invention, the sensor 16 may be an optical fiber that takes pressure measurements, as well as communicates these measurements to the surface. As depicted in Fig. 1, in some embodiments of the invention, the measurements from the sensor 16 may be received by a unit 18 that is located at the surface of the well.

In some embodiments of the invention, other sensors may be run into the well. For example, in some embodiments of the invention, a temperature sensor may be run into the well. In some embodiments of the invention, this temperature sensor may be integrated with the sensor 16, and in other embodiments of the invention, this temperature sensor may be separate from the sensor 16.

In accordance with some embodiments of the invention, a technique may be used to estimate the inflow profile of a well. More specifically, referring to Fig. 2, the technique 30

includes generating (block 32) a mathematical model that relates the pressure and flow rates of the well to an inflow profile. As described in more detail below, the mathematical model may be based on information relating to the well and the formation 14, such as by wireline logging or logging while drilling, or far-field information obtained by field models and seismic studies. Flow, thermal, and compositional effects are taken into account in the model. The model includes a dependency on the inflow profile.

Next, pursuant to the technique 30, the well is produced (block 34) so that hydrocarbons flow from the formation 14 through the well. During this flow, pressure and temperature measurements are taken (block 36); and these measurements, in turn, are used (block 38) to derive the inflow profile, as further described below.

In some embodiments of the invention, to begin the generation of the inflow profile, an initial estimate of the inflow profile may be input into the model. In essence, the model that is generated in block 32 is inverted for the inflow profile. Because multiple pressure measurements are made in the well, corresponding inflow profile estimates at corresponding locations may be derived from the inverted solutions. More specifically, for purposes of diagnosis, the forward measurements using the model are inverted, accounting only for the wellbore and employing a flow model that is commensurate with well geometry and observed production behavior. The model is inverted on hydrodynamic (i.e., rate and pressure) measurements. These rate and pressure measurements may be derived using the sensor 16 and the flow meter 13, for example.

In some embodiments of the invention, the sensors may be interrogated during the normal process of production under non-transient or steady-state or a sequence of steady-state (multi-rate) conditions. To obtain a high-resolution flux profile, the sensors may also be interrogated during a short-duration fluid injection test (with injection, shut-in, and post-shut-in) before commissioning of production or any time during the production phase.

Utilization of the pressure measurements allows a user of the model to determine the location of the inflow, but not the content of the inflow. The content of the inflow is determined by using the temperature measurements. More specifically, by use of the temperature

measurements in the inversion solution, the user may also determine the content of the inflow, i.e., whether the inflow is liquid or gas. The Joule-Thomson effect causes gas to cool upon passage from the formation 14 into the well. This cooling effect, which does not occur if the fluid is liquid, is sensed by the temperature sensor. Therefore, the presence of liquid may be detected if there is no cooling, and the presence of gas may be detected if there is cooling. Furthermore, in some embodiments of the invention, oil and water liquid streams may be discriminated from each other, in some circumstances.

It has been determined that the pressure measurements are directly indicative of intervals of total fluid entry. The differentiation of oil and water is feasible provided that adequate density and viscosity contract exist between the phases. In some embodiments of the invention, the inversion of the pressure profile for a determination of oil and water inflow profiles shows acceptable results provided the inversion is constrained to the total well rate and average water-cut, as may be obtained from a downhole flow meter, for example.

The arrival of gas may have a significant effect on the pressure profile. In some embodiments of the invention, the inversion of the three-phase flow problem requires additional measurements, such as distributed temperature sensing. With this additional information, it has been observed that the liquid inflow profile over time is highly stable, as it is conditioned by the drive mechanism and permeability heterogeneity (i.e., the water-cut cannot be abated in horizontal wells by rate cut-back). Gas influx, however, is rate-sensitive and thus tends to break through toward the heel of the well with increasing rate, unless it is diverted by significant permeability heterogeneities.

In some embodiments of the invention, the advantages of the techniques that are described herein may include one or more of the following. The techniques are non-invasive and therefore are applicable to horizontal wells that have thusfar been impossible to log or difficult to log, such as pumping wells, subsea wells, and extended-reach wells. The sensors, being permanently mounted sensors, may be interrogated at any stage in the life of the well. More specifically, the sensors may be interrogated after commissioning of production, to establish a

baseline for subsequent diagnosis and to assess the effectiveness of the well construction process (i.e., assess the drilling, steering, completion, cleanup, and commissioning of the well). Furthermore, the sensors may be interrogated before and after any remedial or workover operation to assess the impact of the treatment on well performance. Additionally, the techniques that are described herein reveal the reservoir-scale distribution of rock types (at a kilometer scale, for example) in the reservoir horizon, thereby providing important information concerning the placement and positioning of subsequent wells.

Other and different advantages are possible in the various embodiments of the invention described herein.

The following is a more specific example of the determination of an inflow profile. It is assumed for purposes of this example that the well is a horizontal well in a heterogeneous reservoir. Below are discussed the effects of the reservoir environment, the well geometry, the fluid properties, and the production parameters on the wellbore pressure response. Also described below are how for single-phase and two-phase flow problems the inversion of the pressure measurements, constrained to the total well rate (and average water-cut for oil-water flow), yields the inflow profile along the well length. Lastly, described below is the impact of the basic uncertainties of the flow problem and measurements on the quality of the inversion.

In some embodiments of the invention, the algorithm to invert the pressure profile to infer the fluid influx profile aims to minimize an objective function. The objective function is calculated as the sum of the squares of the mismatch between observed and calculated pressures.

The pressure profile is calculated with a multiphase fluid flow model for a pipe that is segmented. The pressure drop between two points along the wellbore is described by the following equation:

$$\Delta p = \Delta p_p + \Delta p_a + \Delta p_f, \qquad \text{Equation 1}$$

wherein the subscripts "p", "a", and "f," represent the potential head, acceleration, and friction pressure drop, respectively. Dividing the total length of the wellbore into N segments, the

pressure at each node and its difference with measured pressure are described by the following relationship:

$$f = \sum_{i=1}^{N} (p_i - p_d)^2, \qquad \text{Equation 2}$$

A Taylor series expansion of the function f about point c, incorporating second order terms, produces the following relationship:

$$f \approx f(c) + \mathbf{g} \cdot \mathbf{q} + \frac{1}{2}(\mathbf{q} \cdot \mathbf{H} \cdot \mathbf{q}), \qquad \text{Equation 3}$$

wherein "**g**" is the gradient of function f, "**q**" is the vector of the influx rate along the wellbore and "**H**" is the Hessian matrix of f.

A minimum of the function f may be found at the point where:

$$\nabla f = 0. \qquad \text{Equation 4}$$

The Levenberg-Marquardt formulation of the inversion of the pressure profile is set forth below:

$$\Delta \mathbf{q} = -(\mathbf{H} + \mu \mathbb{I})^{-1} \nabla f. \qquad \text{Equation 5}$$

The elements of the gradient matrix are calculated according to the following equation:

$$\frac{\partial f}{\partial q_j} = -\sum_{i=1}^{N} (p_i - p_d) \frac{\partial p_d}{\partial q_j}. \qquad \text{Equation 6}$$

The elements of the Hessian matrix are calculated according to the following equation:

$$\frac{\partial^2 f}{\partial q_k q_l} = \sum_{i=1}^{N} \frac{\partial p_d}{\partial q_k} \frac{\partial p_d}{\partial q_l}. \qquad \text{Equation 7}$$

Equation 5 is used to update the initial guess of inflow profile until a determination criterion is met. At that point, the inflow profile has been determined.

Fig. 3 depicts a schematic 46 of a reservoir model used in the following example. The reservoir 46 is a heterogeneous water-drive reservoir that is drained by a 2100 foot horizontal well that is placed in the center. The wellbore is divided into twenty one equally-spaced segments of 100 feet to utilize the multisegment well facility of the simulator. A drift-flux flow model is used for relating the flow and pressure drop in each segment. For the base case the well is selectively completed and open to flow across three intervals with a constant total liquid rate of 10,000 STB/D. The following table summarizes the basic parameters of the model:

RESERVOIR-WELLBORE PARAMETERS	
Model dimensions, feet × feet × feet	4000 × 3000 × 400
Grids (uniform)	40 × 30 × 20
Aquifer type	Carter-Tracy
Average Permeability K (isotropic), md	265
Average Porosity ϕ	0.15
Water Saturation S_{wc}	0.2
Relative Permeabiltiy - Oil K_{ro} (S_w=.2), md	0.8
Relative Permeability – Water K_{rw}(S_w=1), md	1.0
Relative Permeability – Gas K_{rg} (S_g=0), md	0.8
Relative Permeability – Liquid $K_{r\text{-}liq}$ (S_g=.8), md	0.9
Density – Oil ρ_o (base case), °API	35
Viscosity – Oil μ_{ob} (base case), cp	1
Formation Volume Factor – Oil B_{ob} (base case), RB/STB	1.2
Solution Gas-Oil Ratio R_{sb} (base case), scf/STB	1000
Pressure P_b (base case), psi	2700
Pressure – Initial P_i (at OWC), psi	4000
Well placement (heel to toe)	(7,15,10) to (27, 15, 10)
Well standoff (to OWC), feet	100

Well length, feet	2100
Well Inner Diameter, feet	0.3
Well roughness, feet	0.001
Well rate (base case), STB/D	10,000

Table 1

Fig. 4 depicts a production profile of the well. The simulation run is terminated when the water-cut (WCT) reaches approximately 80 percent. Fig. 4 depicts a graph 52 that show a constant fluid rate of 10,000 STB/D from the well, a graph 50 that depicts the water-cut (WCT) and a graph 54 that depicts the oil rate from the well. Described below are snapshots of well behavior when the water-cut is 0 percent, 30 percent, and 60 percent. This corresponds to elapsed times of 0, 300, and 900 days, respectively.

Fig. 5 depicts the liquid influx profile of the well at these snapshots. More specifically, Fig. 5 depicts a graph 56 of a water-cut of zero, a graph 58 showing the fluid influx for a 30 percent water-cut, and graph 60 depicts the fluid influx for a 60 percent water-cut. It is noted that the influx profile is heavily skewed toward the heel of the well, with over half of the production coming through the heel and less than half through the middle and end intervals. This is because of the additional drawdown imposed on the formation at the heel and the better connectivity of the well to the aquifer in this section of the well. The influx profile of the well is fairly stable over time, with a gradual rise in the heel and receding of influx elsewhere.

Fig. 6 depicts a graph 62 of the water influx of the well and a graph 64 of the oil influx of the well. Both of these influxes are shown for a 30 percent water-cut. As depicted, most of the water is produced through the heel section of the well. Again, the preferred connectivity to the aquifer is the cause of this behavior.

Fig. 7 depicts a snapshot of water saturation when the well produces at a 30 percent water-cut. The skewed encroachment is fairly evident.

More particularly, Fig. 8 depicts a graph that shows the total production rate and water-cut. As depicted in Fig. 8, this total fluid rate changes abruptly. However, the water-cut,

depicted by the graph 66, is relatively insensitive to the rate variations.

Fig. 9 depicts graphs 70, 72, and 74 that show pressure profiles of the well at a 0 percent, 30 percent, and 60 percent water-cut, respectively. The toe-to-heel pressure drop is about 55 pounds per square inch (psi), most of which occurs in the final section of the casing (i.e., approximately the last 500 feet of the casing). This is because the flow velocity increases along the path of flow due to the distributed nature of inflow (sort of an "avalanche" effect). The final fluid velocity in this example is about 3.3 feet per second. Greater pressure drops may be observed in high-velocity flows (flows produced in smaller internal diameter and/or gas influx, for example).

The shift of the pressure profile with time reflects the reduction of fluid mobility and the formation due to the onset of a two-phase flow (i.e., a relatively permeability effect). This shift is a relatively uniform drop of about 25 psi from the initial production to when the water-cut reaches 30 percent. Due to the shift in the pressure profile, a greater drawdown is required to maintain a constant well rate. Therefore, the pressure profile is sensitive to phase mobility in the formation.

A distinguishing feature of the pressure profile is the break (i.e., the slope change) that occurs across the intervals of fluid influx. This suggests that the zones of fluid influx may be identified with multipoint pressure measurements. Fig. 10 depicts graphs 76, 78, and 80 depicting the pressure gradient along the wellbore for water-cuts of 0 percent, 30 percent, and 60 percent, respectively. Fig. 10 depicts the slope of the pressure profile over the length of the well. As seen, the three influx intervals exhibit step changes in slope.

Fig. 11 depicts graphs 82, 84, and 86 of the pressure gradient along the wellbore for water-cuts of 0 percent, 30 percent, and 60 percent, respectively. Fig. 11 is a plot of the pressure gradient corresponding to a liner completion, where influx is not limited to particular intervals. The comparatively monotonous rise in slope reflects the more distributed nature of the inflow. The wellbore pressure drop is of the order of 80 psi, greater than the selective completion case, as expected due to the earlier influx of fluid into the wellbore. Variations in intensity of influx,

however, can be detected from fluctuations of the slope. This reflects the heterogeneous nature of the formation. The change of this profile with increasing water-cut is reflective of the mobility effect mentioned previously.

Fig. 12 depicts graphs 88, 90, and 92 of the fluid influx for water-cuts of 0 percent, 30 percent, and 60 percent, respectively. Fig. 12 shows the influx profiles for the base case of a selective sandface completion, but for a formation saturated with viscous oil (an oil having a viscosity of 10 cp, for example). A greater change in influx profile with time (compared to a 1 cp case, for example) is observed and may be attributed to the greater variation of drawdown in the formation as encroachment progresses with corresponding adjustment of wellbore influx profile to sustain a constant production rate. Therefore, a higher contrast in mobility between the phases leads to greater change in fluid influx with time.

Various other parameters affect the pressure. For example, Fig. 13 depicts graphs 94, 96, and 98 of a pressure for water-cuts of 0 percent, 30 percent, and 60 percent, respectively, for the case where special undulations on the pressure profile are present. This indicates that for interpretation purposes a good description of the well trajectory may be required in some embodiments of the invention, such that pressure variations due to the horizon are not attributed to influx.

Fig. 14 depicts graphs 101, 102, and 104, respectively, depicting a pressure for different free gas rates of 9400 Mscf/D, 5200 Mscf/D, and 1700 Mscf/D, respectively. Thus, Fig. 14 depicts pressure profiles when gas is permitted to break into the well. A large increase in the total pressure drop in the wellbore is noted. Also, it is observed that, despite the heterogeneity of the formation, the gas entry is heavily skewed towards the heel, as depicted in Fig. 15. This is explained by the greater mobility of the gas phase in the formation and the greater sensitivity to wellbore frictional losses. Fig. 15 depicts graphs 106, 108, and 110 that show the free gas influx for total free gas rates of 9400 Mscf/D, 5200 Mscf/D, and 1700 Mscf/D, respectively.

Fig. 16 depicts graphs 112 and 114 of the true influx and inversion result, respectively for the liner completion when the well is producing under single-phase flow conditions. As shown,

the inversion result graph 114 closely follows the true influx graph 112.

Fig. 17 depicts graphs 116 and 118 of the true influx and inversion results, respectively, for the case where the hydraulic roughness of the casing is in error by a factor of 10 (hence, the friction coefficient is in error). However, even with this error, as depicted in Fig. 17, the inversion results are still quite reasonable.

Figs. 18 and 19 depict, respectively, the impact of a uniform and random measurement error on the quality of inversion. More specifically, Fig. 18 depicts a graph 120 showing the true influx and a graph 122 depicting the inversion result for the case of uniform measurement error. Fig. 19 depicts graphs 124 and 126 showing a true influx and the inversion result, respectively, for random measurement error. The key observation here is that the quality of the inversion depends on the accuracy of pressure measurement from one node to the other, i.e., relative accuracy, in some embodiments of the invention. For purposes of improving the quality of the inversion, the measurement error may be minimized by the calibration of pressure reading with respect to the well trajectory during production downtime.

Figs. 20 and 21 depict the results of inversion for the selective completion scenario under two-phase flow conditions. More specifically, Fig. 20 depicts graphs 128 and 130 showing the true influx and the inverted influx, respectively, for the selected completion scenario and Fig. 21 depicts graphs 132 and 134 depicting a water influx and oil influx obtained from the inversion. As depicted, a very good match of total fluid influx profile is obtained, as well as a reasonable match of oil and water influx. The quality of the phase influx estimation, however, may deteriorate with reduced contrast between the pressure volume temperature (PVT) properties of the two phases.

As a more specific example of the temperature analysis, the temperature analysis, in some embodiments of the invention, assesses the magnitude of the cooling that results from gas entry and expansion in horizontal wells, to develop a basis for discrimination of gas-rich and liquid-laden streams that form the total fluid influx. An approximate relationship between the in-situ gas-liquid ratio and the observed cooling is sought to contribute to the problem of resolving

the inflow profile of horizontal wells.

In the following scenario, a simple model of a gas-cap drive reservoir is used, where the withdrawal rate induces cusps into the well. The basic parameters used in this example are summarized in the following table:

RESERVOIR-WELLBORE PARAMETERS		
	Low shrinkage oil	High shrinkage oil
Model dimensions, feet × feet × feet	4000×3000×220	4000×3000×220
Grids (uniform)	40 × 30 × 11	40 × 30 × 11
Permeability K (isotropic), md	100	100
Porosity ϕ	0.15	0.15
Water Saturation S_{wc}	0.20	0.20
Solution Gas-Oil Ratio R_s, Mscf/STB	0.2	1.2
Pressure P_b (base case), psi	2303	3000
Pressure – Initial P_i (at GOC), psi	2303	3000
Relative Temperature T_r (at GOC), °F	160	160
Rock thermal conductivity, Btu/foot/D/°F	24	24
Rock heat capacity, Btu/foot^3/°F	35	35
Well thermal resistance, (Btu/foot-day-°F)$^{-1}$	0.114	0.114
Well placement (heel to toe)	(11,21,8) to (29,21,8)	(11,21,8) to (29,21,8)
Well standoff (to GOC), feet	20	100
Well length, feet	1900	1900
Well Inner Diameter, feet	0.3	0.3
Well roughness, feet	.006	.006
Inflow intervals (x-grids)	(16-18), (22-23) and (27-28)	(16-18), (22-23) and (27-28)

Table 2

It has been determined that an important feature here is the PVT properties of the crude. Two black-oils of contrasting volatility (low-shrinkage and high-shrinkage) are depicted for this

purpose. Their properties are depicted in Table 2 above.

Fig. 22 depicts the dependency of the wellbore temperature facing the inflow interval to the in-situ gas/oil ratio at that interval. This is shown in Fig. 22 for several snapshots during the life of the well. More specifically, Fig. 22 depicts graphs 136, 138, and 140 showing the temperature at 105, 380, and 730 days, respectively. To isolate this relationship, the results were generated for the case of a selective completion with only one interval open to flow. As depicted in Fig. 22, the cooling increases with an increasing gas/oil ratio and also increases with time, as there is continued cusping of the cooler gas from the gas-cap during the course of production.

Fig. 23 depicts the wellbore temperature profile in a selective completion with three inflow intervals, at three time slices. More specifically, Fig. 23 shows three graphs 142, 146, and 148 that each depict a temperature profile over the segments at a different time. This example relates to a low-shrinkage crude and thus, minimal wellbore cooling is observed (cooling less than 1 °F, for example).

Fig. 24 depicts wellbore temperature cooling behavior for a gas-cap drive model having high-shrinkage crude. More particularly, Fig. 24 depicts graphs 150, 152, 154, and 156 that show the temperature for GOR's of 1.4, 5.7, 12.1, and 16.6 Mscf/STB, respectively. As depicted in Fig. 24, wellbore cooling of up to 2 °F is observed.

In some embodiments of the invention, the inflow profile of a horizontal well may be diagnosed with in-situ sensors. Intervals of fluid influx may be identified based on variation of pressure gradient in the wellbore. As such, intervals of no influx can also be identified. Discrimination of liquid and gas-rich inflow is, in principle, possible based on the degree of cooling observed in the wellbore as measured by distributed temperature sensing systems. From compositional modelling, cooling of up to 2 °F may be observed in the well, commensurate with the producing gas/oil ratio. A constant wellbore temperature profile, consistent with well trajectory and native geothermal gradient, therefore, is indicative of pure liquid influx. Discrimination of oil and water influx, however, is dependent on the contrast between the PVT properties of the phases, notably density.

Referring to Fig. 25, in some embodiments of the invention, the determination of the inflow profile may be performed by program instructions 206 that are stored in a memory 204 of the computer 200. More specifically, the computer 200 may include a processor 210 (a microprocessor, for example) that executes the program 206 for purposes of producing an inflow profile from pressure, temperature, and flow rate measurements. As discussed above, the generation of the inflow profile may be aided by initial "guesses" of the inflow profile input into the computer 200 by the user. Pursuant to the techniques described above, the instructions 206 determine an inflow profile in response to pressure measurements from the well and indicate content of the inflow profile in response to temperature measurements from the well.

Other embodiments are within the scope of the following claims. For example, in some embodiments of the invention, the model may take into account geomechanical effects for unconsolidated or stress-sensitive formations. Other variations are also possible.

While the present invention has been described with respect to a limited number of embodiments, those skilled in the art, having the benefit of this disclosure, will appreciate numerous modifications and variations therefrom. It is intended that the appended claims cover all such modifications and variations as fall within their scope.

CLAIMS

What is claimed is:

1. A method for estimating the inflow profile of a well, comprising:

generating a well and formation model;

producing the well so that hydrocarbons flow from the formation and through the well;

measuring pressure at a plurality of points along at least a portion of the well without performing an intervention in the well; and

estimating an inflow profile along the portion of the well by use of the plurality of pressure measurements.

1

2. The method of claim 1, wherein the generating comprises obtaining information associated with the well and formation.

3. The method of claim 2, wherein the generating comprises logging the well.

4. The method of claim 2, wherein the logging comprises logging the well while drilling the well.

5. The method of claim 1, wherein the estimating comprises inputting the plurality of pressure measurements into the model and solving the model for the inflow profile.

6. The method of claim 1, further comprising using temperature measurements to determine the inflow profile.

7. The method of claim 6, further comprising determining the presence of inflow at a location by use of the pressure measurements and determining the content of the inflow by use of the temperature measurements.

8. A system usable with a subterranean well, comprising:

a pressure sensor adapted to measure pressure at a plurality of points along at least a portion of the well while the well is in production without requiring an intervention in the well; and

a unit coupled to the pressure sensor and including a well formation model, the unit adapted to estimate an inflow profile along the portion of the well by using the pressure measurements.

9. The system of claim 8, further comprising:

a temperature sensor adapted to measure temperature along the portion.

10. The system of claim 9, wherein the unit is further adapted to use the temperature measurements to estimate the inflow profile.

11. A method usable with a subterranean well, comprising:

obtaining pressure measurements during flowing of the well; and

using a model to determine from the pressure measurements an inflow profile of the well.

12. The method of claim 11, wherein the using comprises:

providing an estimation of the inflow profile to the model; and

refining the estimation using the pressure measurements.

13. The method of claim 12, wherein the refining comprises:

performing an inversion of a function that interrelates the inflow profile to the pressure measurements.

14. The method of claim 11, further comprising:

deploying a sensor into the well; and

obtaining the pressure measurements from the sensor.

15. The method of claim 14, wherein the deploying comprises:

deploying an optical fiber into the well.

16. The method of claim 11, further comprising:

obtaining temperature measurements from the well; and

further basing the determination of the inflow profile on the temperature measurements.

17. The method of claim 16, further comprising:

determining a content of the inflow profile based at least in part on the temperature measurements.

18. An article comprising a computer readable storage medium storing instructions to cause a processor-based system to:

use a model to determine an inflow profile of a well in response to pressure measurements obtained from the well.

19. The article of claim 18, the storage medium storing instructions to cause the processor-based system to:

provide an estimation of the inflow profile to the model; and

refine the estimation using the pressure measurements.

20. The article of claim 19, the storage medium storing instructions to cause the processor-based system to:

perform an inversion of a function that interrelates the inflow profile to the pressure measurements.

21. The article of claim 18, the storage medium storing instructions to cause the processor-based system to:

receive temperature measurements from the well; and

further base the determination of the inflow profile on the temperature measurements.

22. The article of claim 21, the storage medium storing instructions to cause the processor-based system to:

determine a content of the inflow profile based at least in part on the temperature measurements.

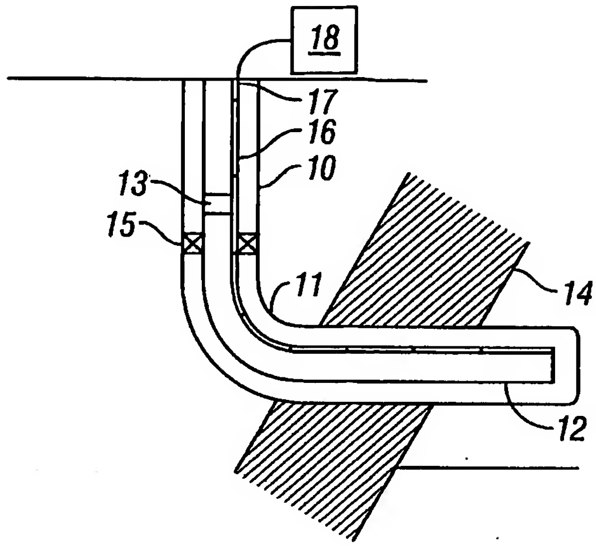

18
17
16
10
13
15
11
14
12

FIG. 1

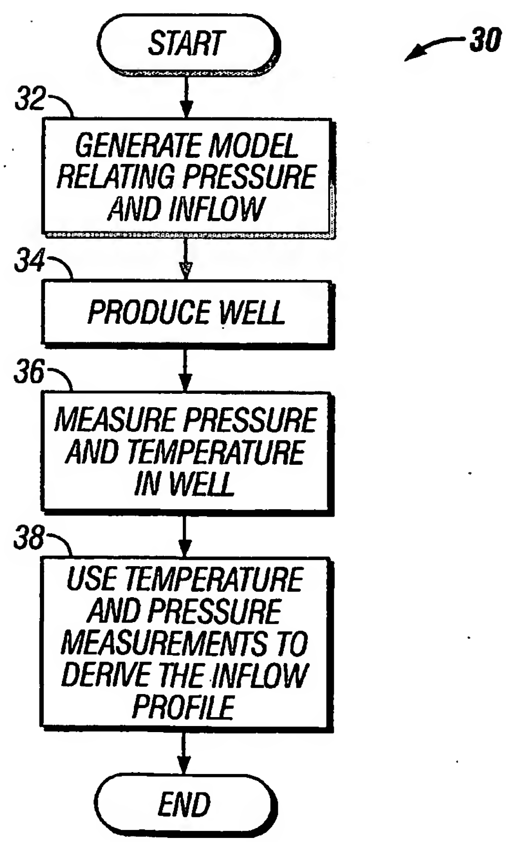

30
START
32
GENERATE MODEL RELATING PRESSURE AND INFLOW
34
PRODUCE WELL
36
MEASURE PRESSURE AND TEMPERATURE IN WELL
38
USE TEMPERATURE AND PRESSURE MEASUREMENTS TO DERIVE THE INFLOW PROFILE
END

FIG. 2

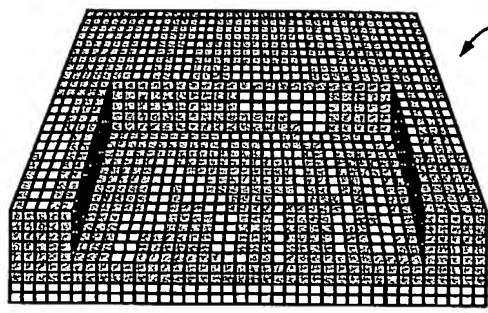

46

FIG. 3

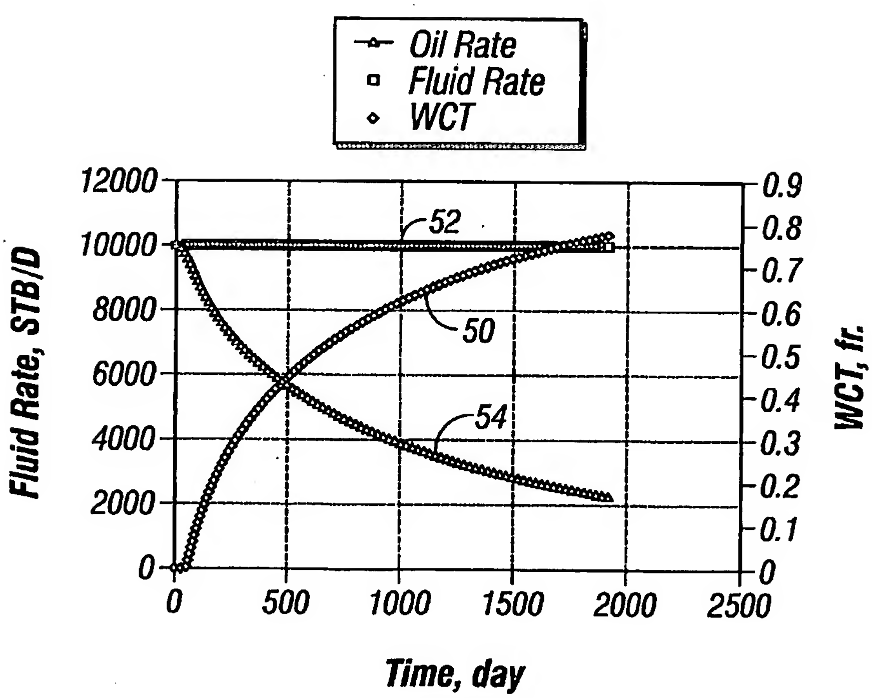

Oil Rate
Fluid Rate
WCT
12000
10000
8000
6000
4000
2000
0
0.9
0.8
0.7
0.6
0.5
0.4
0.3
0.2
0.1
0
0
500
1000
1500
2000
2500
52
50
54
Fluid Rate, STB/D
WCT, fr.
Time, day

FIG. 4

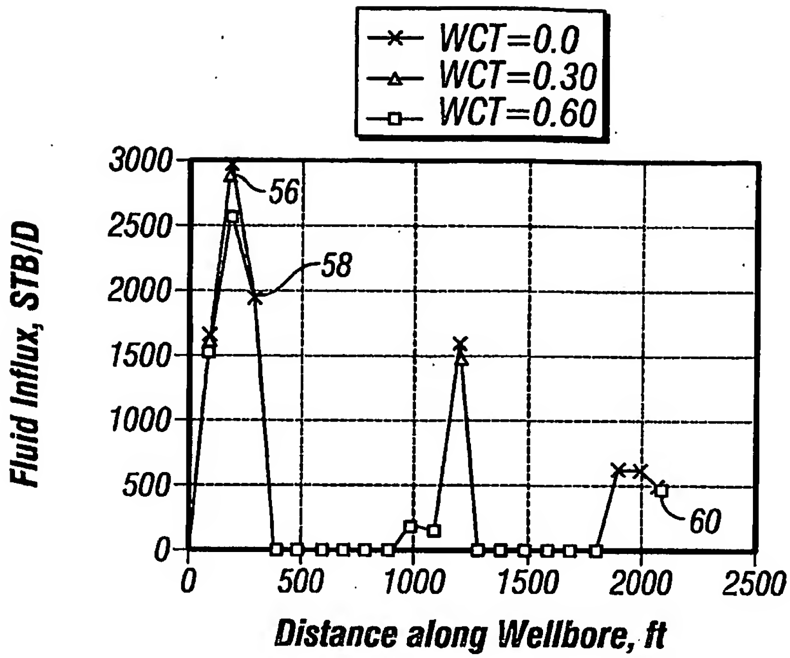

WCT=0.0
WCT=0.30
WCT=0.60
3000
2500
2000
1500
1000
500
0
56
58
60
0
500
1000
1500
2000
2500
Fluid Influx, STB/D
Distance along Wellbore, ft

FIG. 5

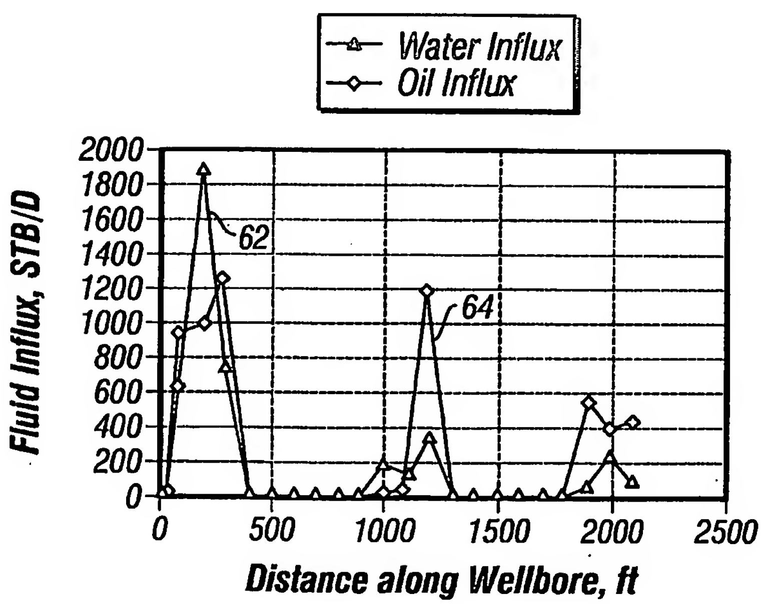

Water Influx
Oil Influx
2000
1800
1600
1400
1200
1000
800
600
400
200
0
62
64
0
500
1000
1500
2000
2500
Fluid Influx, STB/D
Distance along Wellbore, ft

FIG. 6

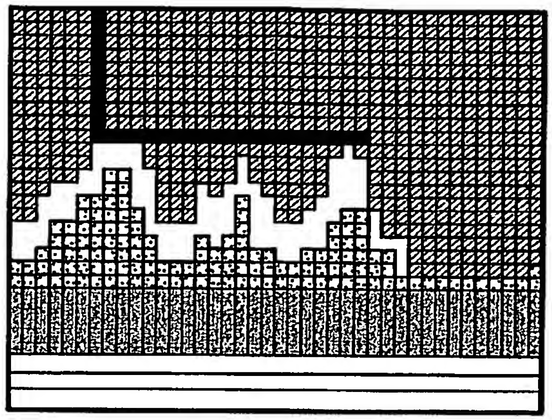


FIG. 7

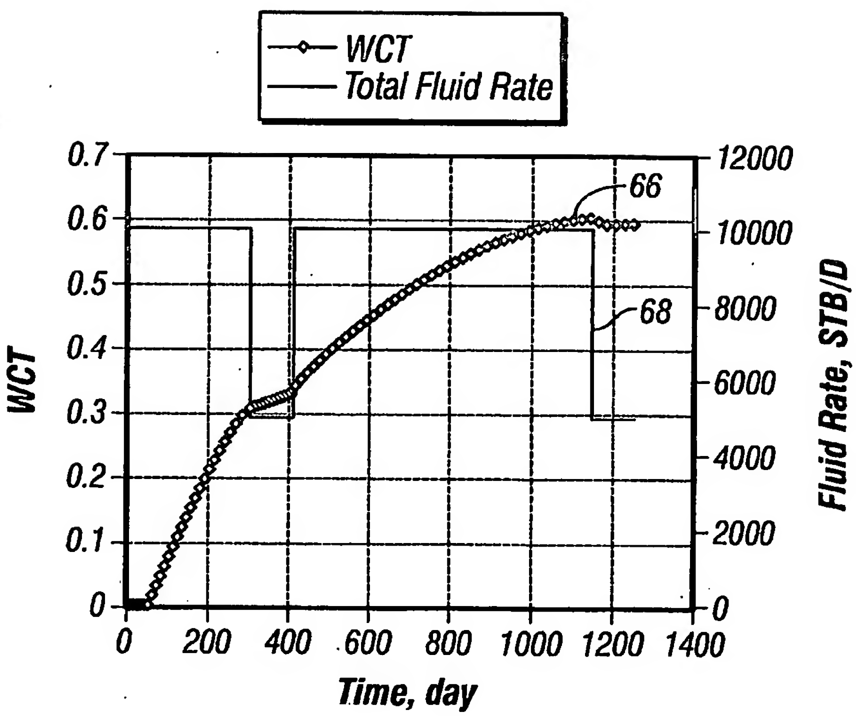

WCT
Total Fluid Rate
0.7
0.6
0.5
0.4
0.3
0.2
0.1
0
WCT
12000
10000
8000
6000
4000
2000
0
Fluid Rate, STB/D
66
68
0
200
400
600
800
1000
1200
1400
Time, day

FIG. 8

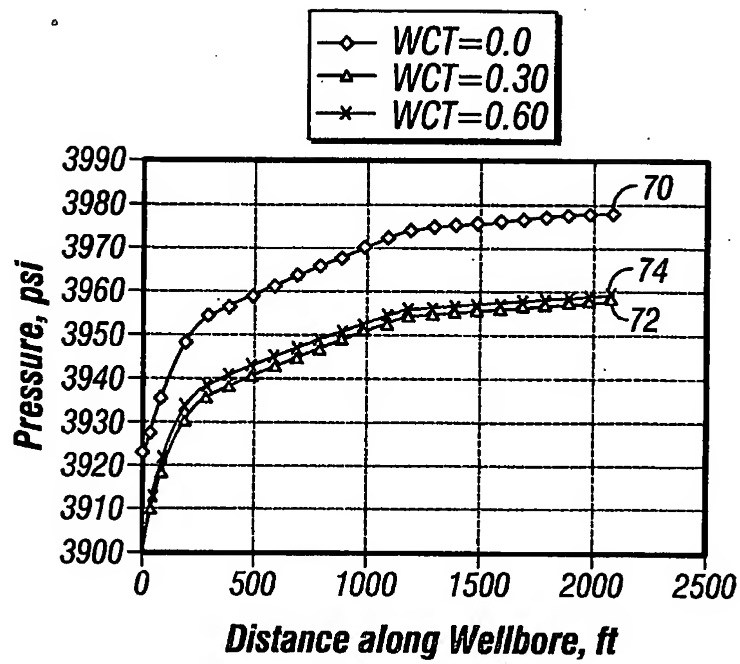

WCT=0.0
WCT=0.30
WCT=0.60
Pressure, psi
3990
3980
3970
3960
3950
3940
3930
3920
3910
3900
0
500
1000
1500
2000
2500
70
74
72
Distance along Wellbore, ft

FIG. 9

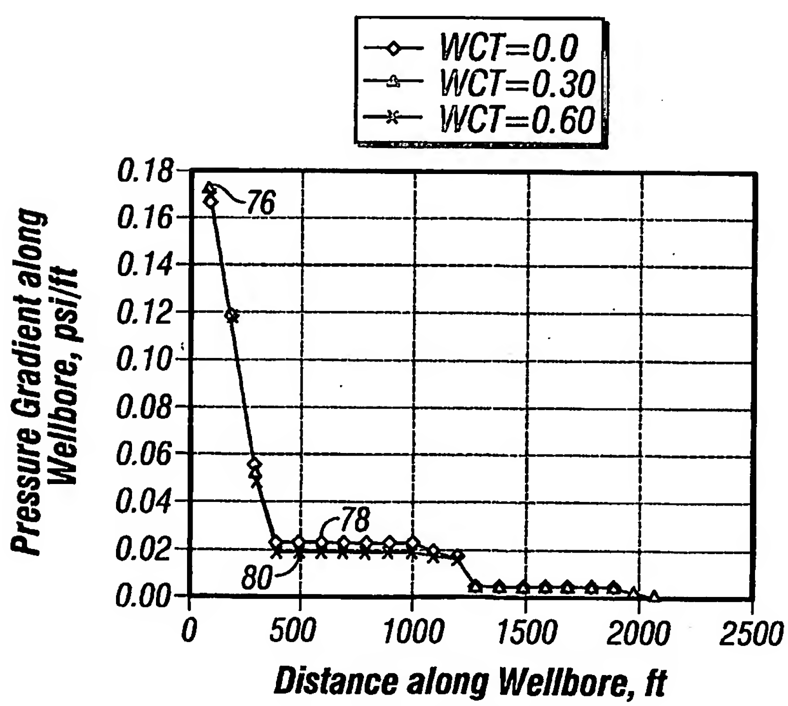

WCT=0.0
WCT=0.30
WCT=0.60
Pressure Gradient along Wellbore, psi/ft
0.18
0.16
0.14
0.12
0.10
0.08
0.06
0.04
0.02
0.00
0
500
1000
1500
2000
2500
76
78
80
Distance along Wellbore, ft

FIG. 10

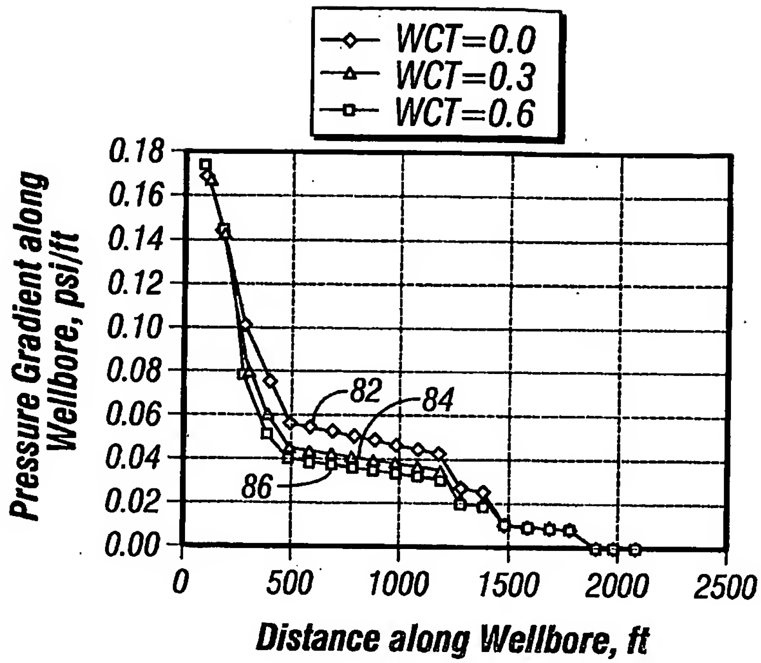

WCT=0.0
WCT=0.3
WCT=0.6
Pressure Gradient along Wellbore, psi/ft
0.18
0.16
0.14
0.12
0.10
0.08
0.06
0.04
0.02
0.00
82
84
86
0
500
1000
1500
2000
2500
Distance along Wellbore, ft

FIG. 11

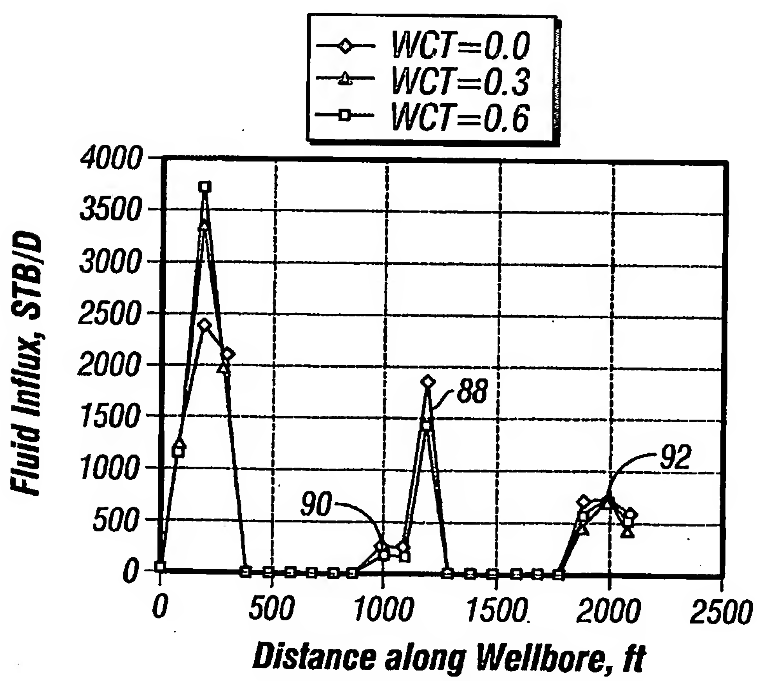
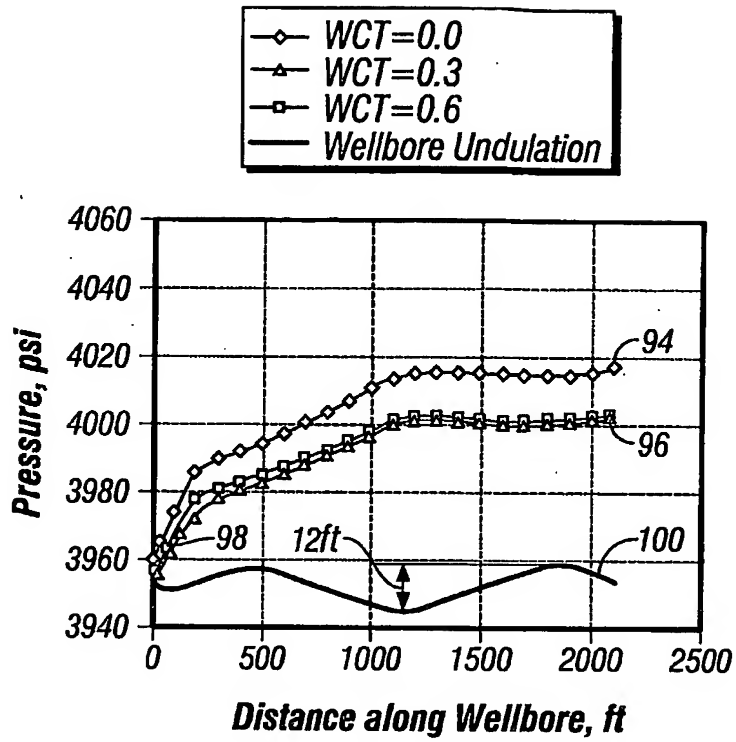
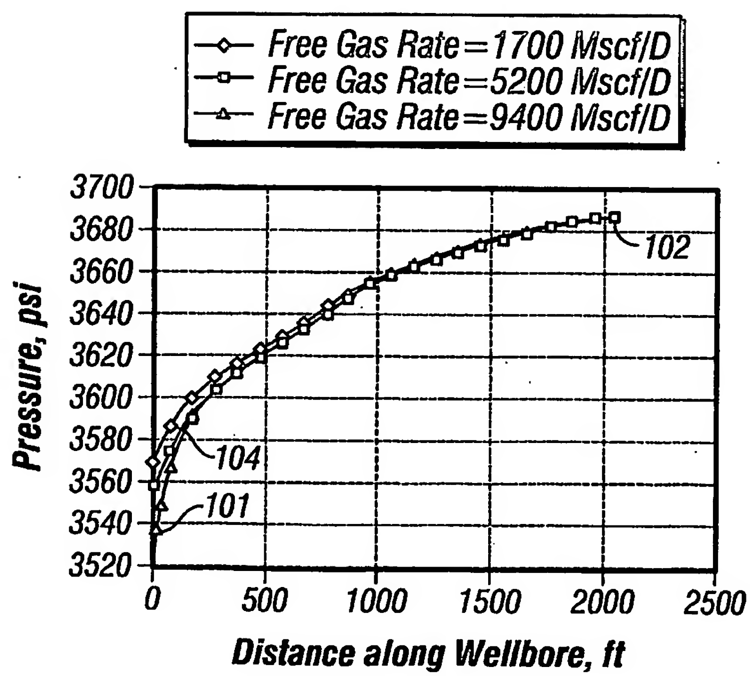

WCT=0.0
WCT=0.3
WCT=0.6
Fluid Influx, STB/D
4000
3500
3000
2500
2000
1500
1000
500
0
88
90
92
0
500
1000
1500
2000
2500
Distance along Wellbore, ft

FIG. 12



WCT=0.0
WCT=0.3
WCT=0.6
Wellbore Undulation
Pressure, psi
4060
4040
4020
4000
3980
3960
3940
0
500
1000
1500
2000
2500
94
96
98
12ft
100
Distance along Wellbore, ft

FIG. 13



Free Gas Rate=1700 Mscf/D
Free Gas Rate=5200 Mscf/D
Free Gas Rate=9400 Mscf/D
Pressure, psi
3700
3680
3660
3640
3620
3600
3580
3560
3540
3520
0
500
1000
1500
2000
2500
102
104
101
Distance along Wellbore, ft

FIG. 14

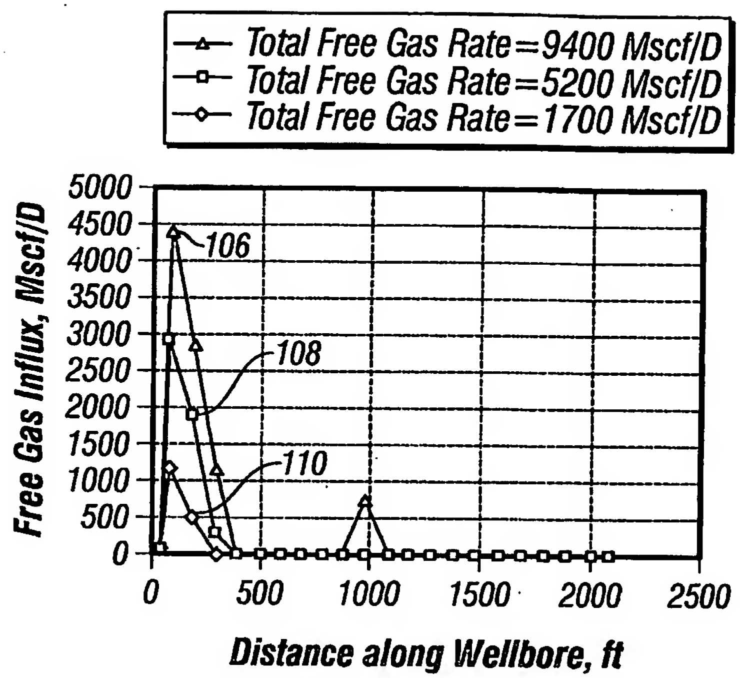

Total Free Gas Rate=9400 Mscf/D
Total Free Gas Rate=5200 Mscf/D
Total Free Gas Rate=1700 Mscf/D
Free Gas Influx, Mscf/D
5000
4500
4000
3500
3000
2500
2000
1500
1000
500
0
106
108
110
0
500
1000
1500
2000
2500
Distance along Wellbore, ft

FIG. 15

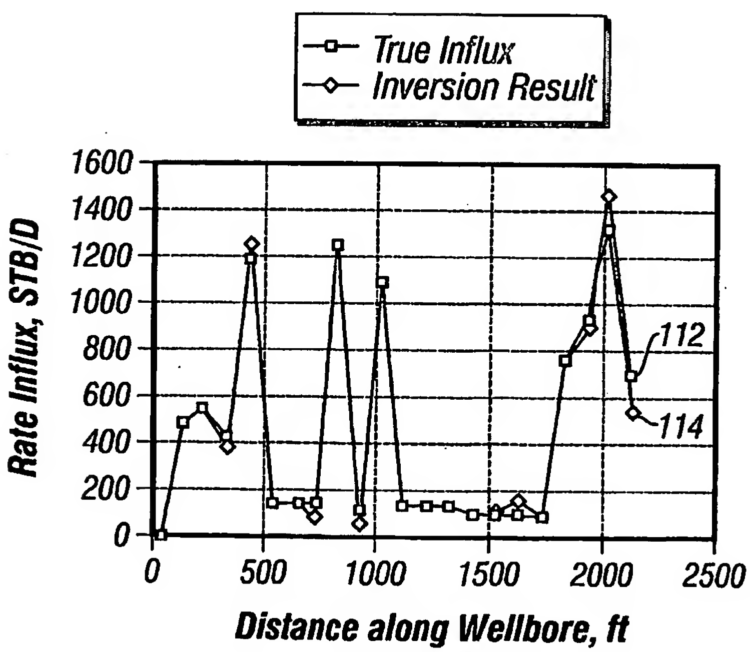

True Influx
Inversion Result
Rate Influx, STB/D
1600
1400
1200
1000
800
600
400
200
0
112
114
0
500
1000
1500
2000
2500
Distance along Wellbore, ft

FIG. 16

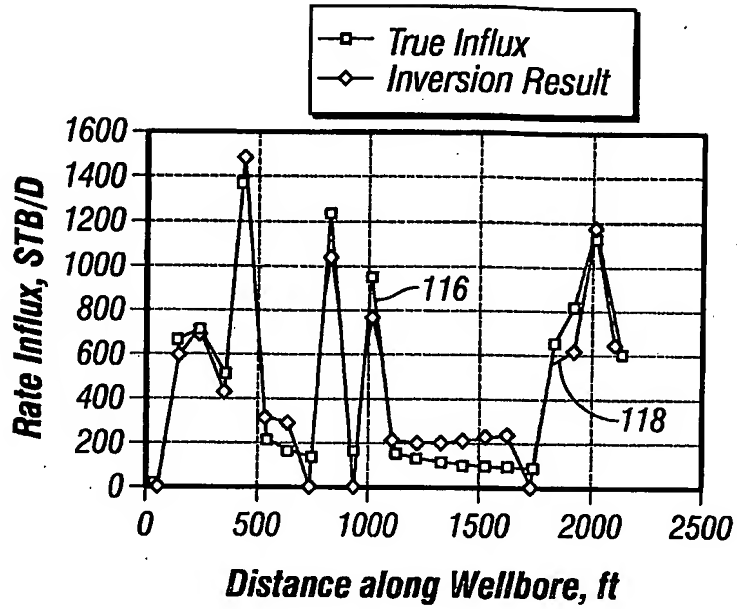

True Influx
Inversion Result
1600
1400
1200
1000
800
600
400
200
0
Rate Influx, STB/D
0
500
1000
1500
2000
2500
Distance along Wellbore, ft
116
118

FIG. 17

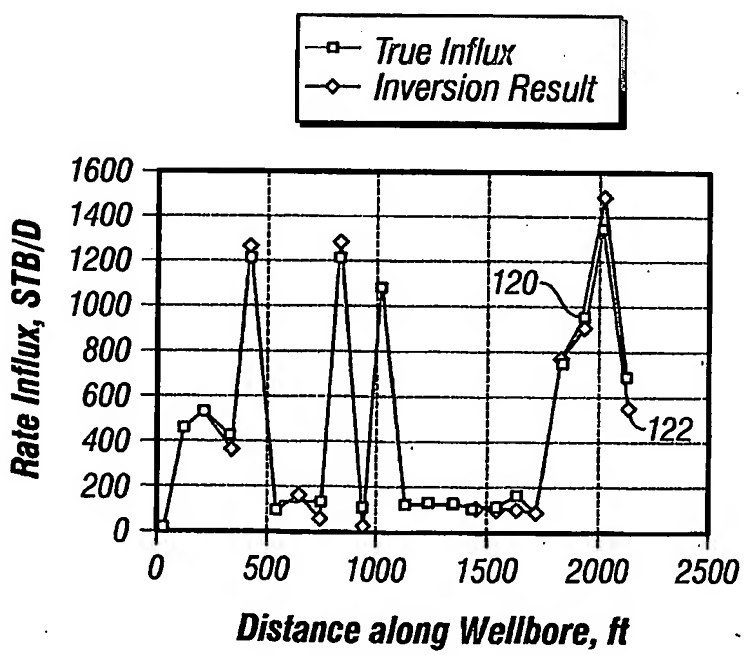

True Influx
Inversion Result
1600
1400
1200
1000
800
600
400
200
0
Rate Influx, STB/D
0
500
1000
1500
2000
2500
Distance along Wellbore, ft
120
122

FIG. 18

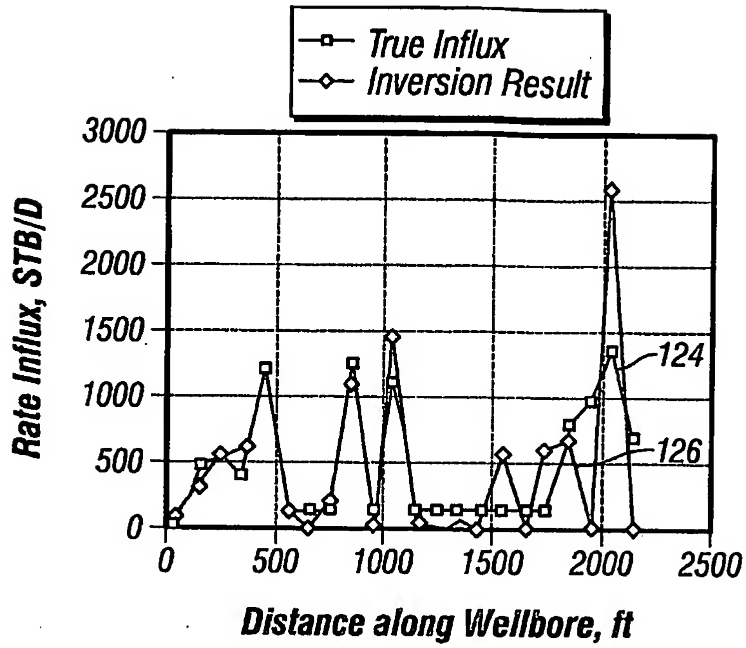

True Influx
Inversion Result
Rate Influx, STB/D
3000
2500
2000
1500
1000
500
0
0
500
1000
1500
2000
2500
124
126
Distance along Wellbore, ft

FIG. 19

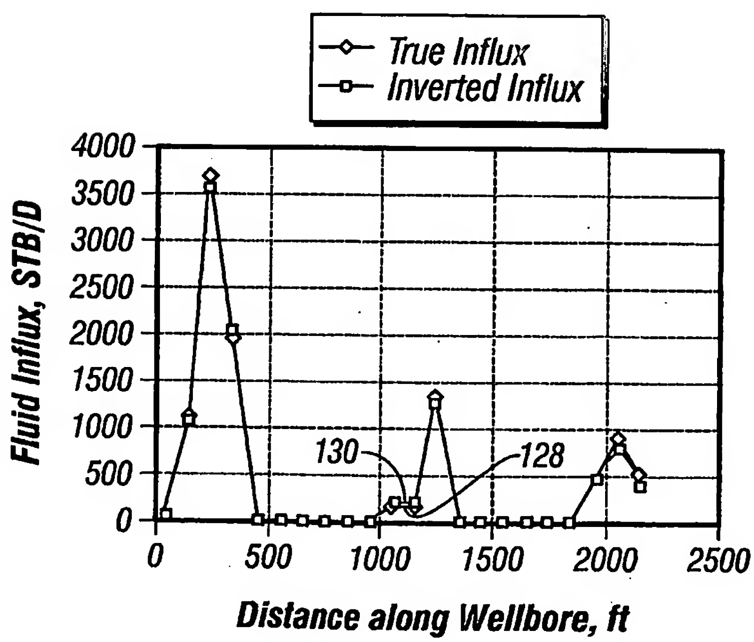

True Influx
Inverted Influx
Fluid Influx, STB/D
4000
3500
3000
2500
2000
1500
1000
500
0
0
500
1000
1500
2000
2500
130
128
Distance along Wellbore, ft

FIG. 20

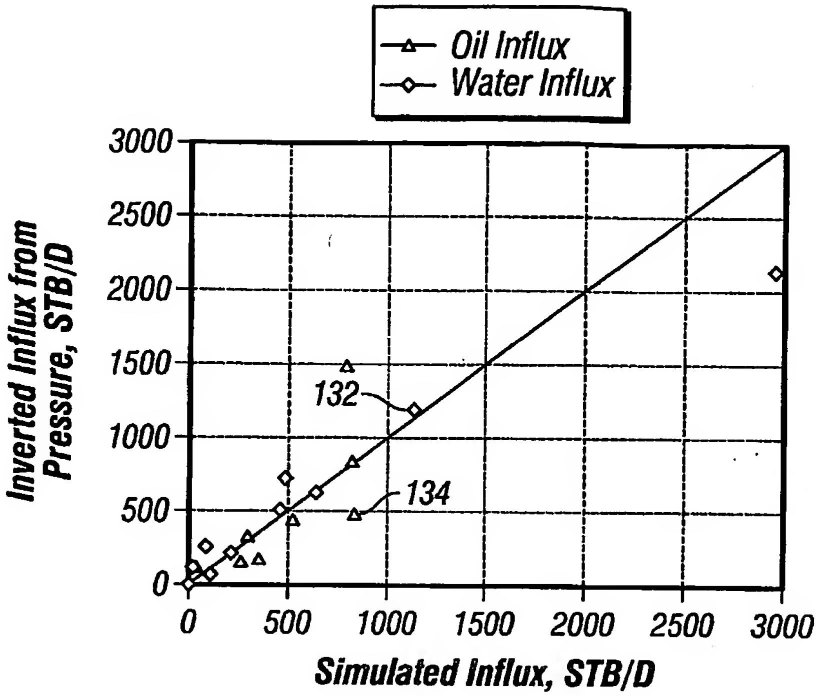

Oil Influx
Water Influx
3000
2500
2000
1500
1000
500
0
Inverted Influx from Pressure, STB/D
132
134
0
500
1000
1500
2000
2500
3000
Simulated Influx, STB/D

FIG. 21

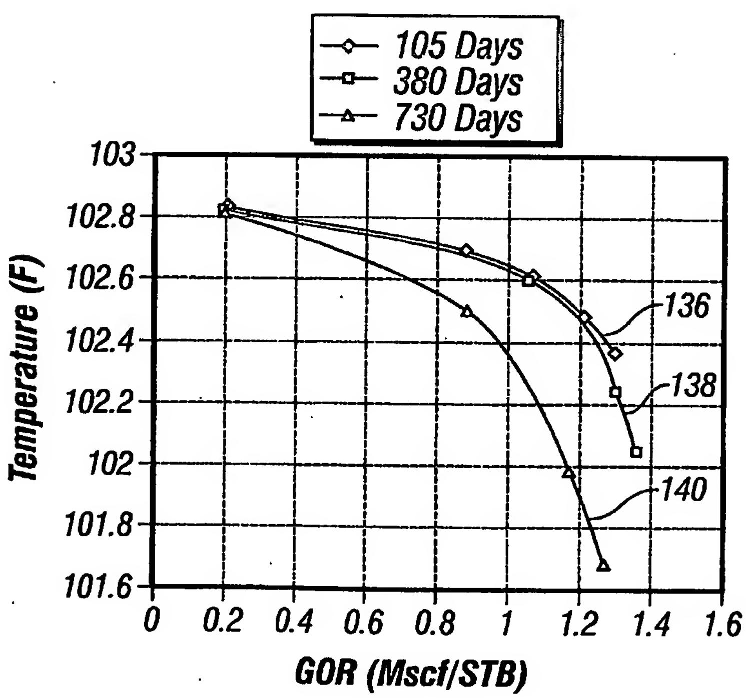
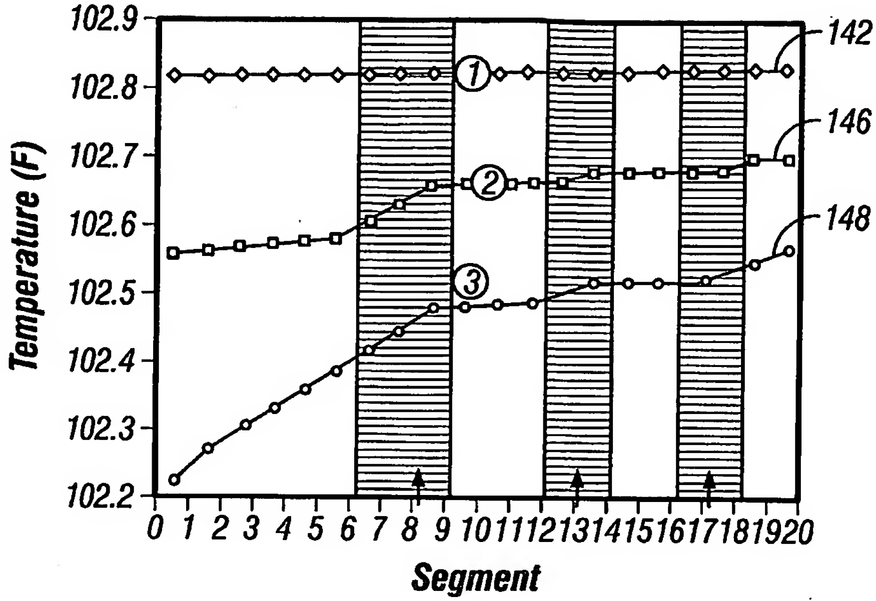
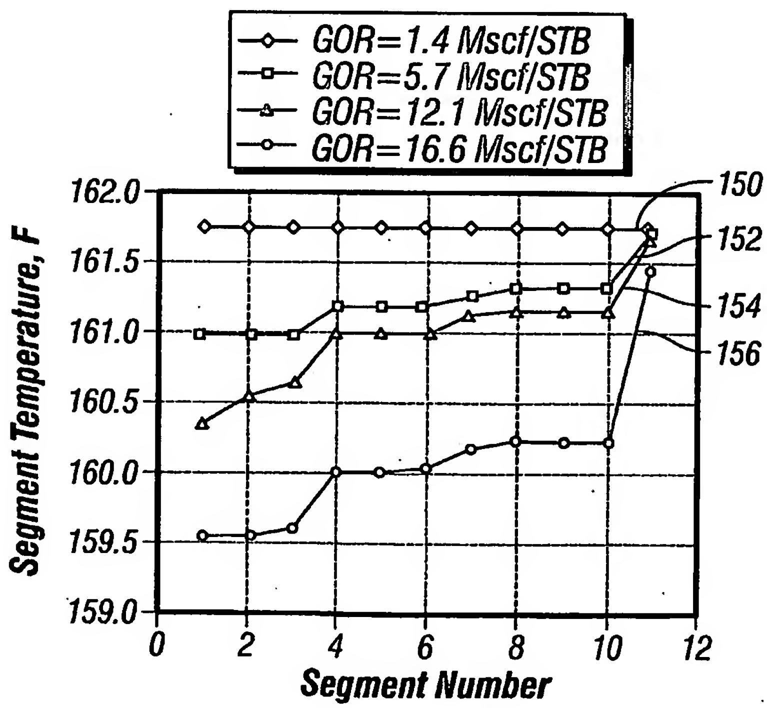

105 Days
380 Days
730 Days
103
102.8
102.6
102.4
102.2
102
101.8
101.6
Temperature (F)
136
138
140
0
0.2
0.4
0.6
0.8
1
1.2
1.4
1.6
GOR (Mscf/STB)

FIG. 22



102.9
102.8
102.7
102.6
102.5
102.4
102.3
102.2
Temperature (F)
1
2
3
142
146
148
0 1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20
Segment

FIG. 23



GOR=1.4 Mscf/STB
GOR=5.7 Mscf/STB
GOR=12.1 Mscf/STB
GOR=16.6 Mscf/STB
162.0
161.5
161.0
160.5
160.0
159.5
159.0
Segment Temperature, F
150
152
154
156
0 2 4 6 8 10 12
Segment Number

FIG. 24

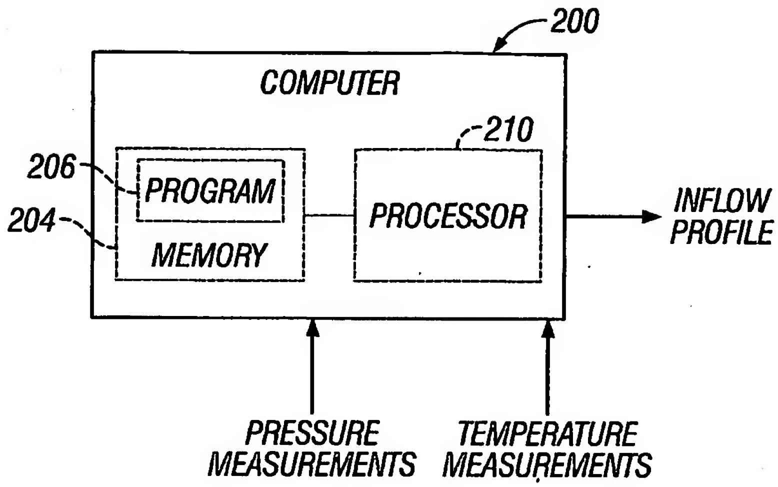

200
COMPUTER
210
206
PROGRAM
204
MEMORY
PROCESSOR
INFLOW PROFILE
PRESSURE MEASUREMENTS
TEMPERATURE MEASUREMENTS

FIG. 25

INTERNATIONAL SEARCH REPORT

International Application No
PCT/GB2004/000760

A. CLASSIFICATION OF SUBJECT MATTER
IPC 7 E21B49/00 E21B47/06

According to International Patent Classification (IPC) or to both national classification and IPC

B. FIELDS SEARCHED

Minimum documentation searched (classification system followed by classification symbols)
IPC 7 E21B

Documentation searched other than minimum documentation to the extent that such documents are included in the fields searched

Electronic data base consulted during the international search (name of data base and, where practical, search terms used)

EPO-Internal

C. DOCUMENTS CONSIDERED TO BE RELEVANT

Category *	Citation of document, with indication, where appropriate, of the relevant passages	Relevant to claim No.
X	US 6 101 447 A (POE JR BOBBY DALE) 8 August 2000 (2000-08-08)	1,2, 5-11,14, 16-18, 21,22
	column 2, line 25 - line 32; figures 1,3-5 column 5, line 29 -column 6, line 28	
Y		3,4,15
X	WO 01/65063 A (HIRSCH JOHN MICHELE ;SAVAGE WILLIAM MOUNTJOY (US); STEGEMEIER GEOR) 7 September 2001 (2001-09-07) page 21, line 18 -page 23, line 22	1,2,8, 11-13, 18-20
A	US 4 803 873 A (EHLIG-ECONOMIDES CHRISTINE) 14 February 1989 (1989-02-14) column 1, line 63 -column 2, line 18; figure 1	1

-/--

[X] Further documents are listed in the continuation of box C.

[X] Patent family members are listed in annex.

* Special categories of cited documents :

"A" document defining the general state of the art which is not considered to be of particular relevance

"E" earlier document but published on or after the international filing date

"L" document which may throw doubts on priority claim(s) or which is cited to establish the publication date of another citation or other special reason (as specified)

"O" document referring to an oral disclosure, use, exhibition or other means

"P" document published prior to the international filing date but later than the priority date claimed

"T" later document published after the international filing date or priority date and not in conflict with the application but cited to understand the principle or theory underlying the invention

"X" document of particular relevance; the claimed invention cannot be considered novel or cannot be considered to involve an inventive step when the document is taken alone

"Y" document of particular relevance; the claimed invention cannot be considered to involve an inventive step when the document is combined with one or more other such documents, such combination being obvious to a person skilled in the art.

"&" document member of the same patent family

Date of the actual completion of the international search	Date of mailing of the international search report
1 June 2004	22/06/2004

Name and mailing address of the ISA	Authorized officer
European Patent Office, P.B. 5818 Patentlaan 2 NL - 2280 HV Rijswijk Tel. (+31-70) 340-2040, Tx. 31 651 epo nl, Fax: (+31-70) 340-3016	Dantinne, P

Form PCT/ISA/210 (second sheet) (January 2004)

International Application No
PCT/GB2004/000760

C.(Continuation) DOCUMENTS CONSIDERED TO BE RELEVANT		
Category °	Citation of document, with indication, where appropriate, of the relevant passages	Relevant to claim No.
Y	BRYANT, CHEN, RAGHURAMAN, SCHROEDER, SUPP, NAVARRO, RAW, SMITH, SCAGGS: "Real-Time monitoring and control of water influx to a horizontal well using advanced completion equipped with permanent sensors" SOCIETY OF PETROLEUM ENGINEERS, vol. SPE, no. 77522, 29 September 2002 (2002-09-29) - 2 October 2002 (2002-10-02), pages 1-16, XP002282728 San Antonio See whole document	3,4,15

INTERNATIONAL SEARCH REPORT

Information on patent family members

International Application No
PCT/GB2004/000760

Patent document cited in search report		Publication date	Patent family member(s)			Publication date
US 6101447	A	08-08-2000	NONE			
WO 0165063	A	07-09-2001	AU	5079501	A	12-09-2001
			CA	2401709	A1	07-09-2001
			EP	1259707	A1	27-11-2002
			NO	20024140	A	30-10-2002
			WO	0165063	A1	07-09-2001
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